RESULTS OF OPERATIONS

Revenues

	Three months ended September 30				Nine months ended September 30			
(Canadian dollars in millions)	2010	2009	$ Change	% Change	2010	2009	$ Change	% Change
Transmission	376	296	80	27	1,002	869	133	15
Distribution	970	831	139	17	2,795	2,620	175	7
Other	14	17	(3)	(18)	47	48	(1)	(2)
	1,360	1,144	216	19	3,844	3,537	307	9
Average Ontario 60-minute peak demand *(MW)*[1]	24,812	21,374	3,438	16	22,119	21,058	1,061	5
Distribution - units distributed to customers *(TWh)*[1]	7.2	6.7	0.5	7	21.6	21.4	0.2	1

[1] System-related statistics are preliminary

The demand for electricity generally follows normal weather-related variations, and, therefore, our energy-related revenues, all other things being equal, will tend to be higher in the first and third quarters than in the second and fourth quarters.

Transmission

Transmission revenues predominantly consist of our transmission tariff, which is based on the monthly peak demand for electricity across our high-voltage network. The tariff is designed to recover revenues necessary to support a transmission system with sufficient capacity to accommodate the maximum expected demand. Demand is primarily influenced by weather and economic conditions. Transmission revenues also include minor amounts of ancillary revenues which are primarily attributable to maintenance services provided to generators and secondary use of our land rights-of-way.

Our transmission revenues were higher by $80 million, or 27%, in the third quarter, and by $133 million, or 15%, in the first nine months, compared to the same periods last year. The average monthly peak demand was higher for both the quarter and the year-to-date period, resulting in an increase in transmission revenue of $43 million and $36 million, respectively. Among other factors, weather was generally milder over the winter months and unseasonably hot in the third quarter, as compared to the prior year.

The Ontario Energy Board (OEB) rendered its decision on our 2009 and 2010 transmission rate application on May 28, 2009 following an extensive written and oral review. The resulting tariff increases approved effective July 1, 2009 and January 1, 2010 support our investments in respect of the Ontario Power Authority's (OPA) supply mix policy, including the phase-out of coal-fired generation and addressing aging infrastructure. These increases resulted in higher third quarter revenues of $32 million and higher year-to-date revenues of $92 million. We also experienced higher revenues of $4 million in the quarter and $13 million on a year-to-date basis associated with certain OEB-approved deferral accounts.

Transmission tariff revenue increases were partially offset in the year-to-date period by lower ancillary revenues of approximately $8 million due to the impact of the May 28, 2009 OEB decision. Consistent with this decision, ancillary revenues received in excess of OEB-approved levels are recorded in a regulatory liability account and are not recognized as revenue. Ancillary revenues increased slightly in the quarter by $1 million.

Distribution

Distribution revenues include our distribution tariff, as well as amounts to recover the cost of purchased power used by our customers. Accordingly, our distribution revenues are influenced by the amount of electricity we distribute, the cost of purchased power and our approved distribution tariffs. Distribution revenues also include a minor amount of ancillary distribution services revenues, such as fees related to the use of our poles by the telecommunications and cable television industries, and miscellaneous charges such as those for late payments.

Distribution revenues increased by $139 million, or 17%, in the third quarter, and by $175 million, or 7%, in the first nine months compared to the same periods last year. Well over half of this change is attributable to the recovery of higher purchased power costs of $91 million in the third quarter and $104 million in the first nine months, as described below under "Purchased Power."

Increases in revenue reflect two OEB decisions on the distribution tariff rates of our subsidiary, Hydro One Networks Inc. (Hydro One Networks). On May 13, 2009, the OEB approved new tariff rates under the third generation Incentive Rate Mechanism (IRM) effective May 1, 2009. On April 9, 2010, the OEB approved new tariff rates following our cost of service application effective May 1, 2010. Both decisions followed extensive written and oral reviews of our evidence submitted for the maintenance and investment requirements of the distribution system, including those to support renewable distributed generation. The new OEB-approved tariff rates effective May 1, 2010 resulted in higher distribution revenues of $26 million during the third quarter. The impact of both decisions on the year-to-date revenues was $55 million. These tariff rate increases support the maintenance and investment requirements of our distribution system and enable the safe and reliable delivery of electricity to our customers throughout Ontario. The April 9, 2010 decision also resulted in increased revenue related to the recovery of smart meter investments and smart grid investments of $4 million in the quarter and $16 million in the first nine months. We also experienced higher revenues of $6 million in the quarter and $8 million on a year-to-date basis associated with certain OEB-approved deferral accounts.

Higher energy consumption, resulting from the unseasonably hot weather in the third quarter, increased our distribution revenues by $12 million in the quarter. This increase was more than offset by the impact of milder weather in the first quarter of this year resulting in lower energy consumption of $2 million in the first nine months. In addition, revenues associated with the recovery of a distribution-related regulatory account ceased effective April 30, 2010, resulting in a revenue reduction of $6 million in the third quarter and $10 million in the nine-month period.

We also experienced higher ancillary revenues of approximately $6 million in the quarter and $4 million on a year-to-date basis.

Purchased Power

Purchased power costs incurred by our Distribution Business represent the cost of electricity delivered to customers within our distribution service territory and comprise the wholesale commodity cost of energy, the Independent Electricity System Operator's (IESO) wholesale market service charges, and transmission charges levied by the IESO. The commodity cost of energy for certain low-volume and designated customers is based on the OEB's Regulated Price Plan (RPP), which consists of a two-tiered pricing structure with threshold amounts and a separate pricing structure for RPP customers on time-of-use billing, both adjusted twice annually. Customers who are not eligible for the RPP pay the market price for electricity, adjusted for the difference between market prices and the prices paid to generators under the *Electricity Restructuring Act, 2004*. A summary of the RPP impacting the reporting period is provided below.

	Tier Threshold (kWh/month)		Tier Rates (cents/kWh)	
Effective Date	**Residential**	**Non-Residential**	**First Tier**	**Second Tier**
November 1, 2008	1,000	750	5.6	6.5
May 1, 2009	600	750	5.7	6.6
November 1, 2009	1,000	750	5.8	6.7
May 1, 2010	600	750	6.5	7.5

RPP Time-of-Use	Rates (cents/kWh)		
Effective Date	**On Peak**	**Mid Peak**	**Off Peak**
May 1, 2010	9.9	8.0	5.3

Purchased power costs increased in 2010 by $91 million, or 17%, to $638 million in the third quarter and by $104 million, or 6% to $1,835 million in the first nine months compared to the same periods last year. The increase for the quarter primarily reflects higher demand for electricity of $78 million, the impact of changes in the OEB's RPP rate for residential and other eligible customers of $10 million, increased transmission charges due to the OEB's transmission rate decision effective January 1, 2010 of $8 million and higher charges levied by the IESO of $2 million. The effect of these increases was partially offset by the impact of lower purchased power costs for customers who are not eligible for the RPP of $7 million. The increase for the nine-month period reflects the impact of higher OEB RPP rates for residential and other eligible customers of $41 million, higher purchased power costs for customers who are not eligible for the RPP of $33 million, higher transmission charges as a result of the OEB's transmission rate decisions effective July 1, 2009 and January 1, 2010 of $25 million and higher demand for electricity of $17 million. The effect of these increases was partially offset by lower wholesale market service charges levied by the IESO of $12 million.

Operation, Maintenance and Administration

Our operation, maintenance and administration costs consist of labour, material, equipment and purchased services which support the operation and maintenance of the transmission and distribution systems. Also included in these costs are property taxes and payments in lieu thereof on our transmission and distribution lines, stations and buildings.

Operation, maintenance and administration costs for each of our three business segments were as follows:

	Three months ended September 30				Nine months ended September 30			
(Canadian dollars in millions)	2010	2009	$ Change	% Change	2010	2009	$ Change	% Change
Transmission	90	109	(19)	(17)	300	332	(32)	(10)
Distribution	147	144	3	2	432	418	14	3
Other	16	14	2	14	45	41	4	10
	253	267	(14)	(5)	777	791	(14)	(2)

Transmission

Operation, maintenance and administration expenditures incurred to sustain our high-voltage transmission stations, lines and rights-of-way decreased by $19 million, or 17%, in the quarter and by $32 million, or 10%, on a year-to-date basis, compared to the same periods last year. Within our work programs, we continued to invest in the safe and reliable operation of our transmission system that spans Ontario. Our work program expenditures were lower by $8 million in the quarter and by $2 million on a year-to-date basis, compared to the same periods last year. In the quarter, we experienced lower expenditures associated with planned station maintenance, particularly on power equipment, lower requirements for engineering support and lower expenditures in our forestry programs associated with the advancement of these programs given favourable weather conditions in the first half of the year. On a year-to-date basis we experienced higher expenditures associated with our corrective station maintenance programs to support aging infrastructure, partially offset by lower planned line maintenance activities. Our expenditures in support of our transmission system were lower by $11 million in the third quarter and by $30 million in the first nine months. These reductions primarily reflect the redirection of resources and the elimination of capital tax by the Canada Revenue Agency (CRA) effective July 1, 2010.

Distribution

Operation, maintenance and administration expenditures incurred to sustain our low-voltage distribution system increased by $3 million, or 2%, in the quarter and by $14 million, or 3%, on a year-to-date basis, compared to the same periods last year. Our work program expenditures were higher by $3 million in the quarter and by $14 million on a year-to-date basis, compared to the same periods last year. In both the quarter and the year-to-date periods, we experienced increased expenditures associated with higher requirements within our forestry programs related to brush control and line clearing, and had increased requirements within our engineering support program. Additionally, on a year-to-date basis, we experienced increased requirements within our smart meter program due to ongoing operational costs for installed meters. These expenditures were partially offset in the quarter and in the year-to-date period by lower storm restoration requirements, and lower field meter reading costs as installed smart meters begin to reach the required level of reliable communication. Our expenditures in support of our distribution system were unchanged in both the quarter and year-to-date periods, reflecting increases as a result of the redirection of resources, offset by the elimination of capital tax by the CRA effective July 1, 2010.

Depreciation and Amortization

Depreciation and amortization expense increased by $11 million, or 8%, to $150 million in the third quarter and by $41 million, or 10%, to $433 million in the first nine months compared to the same periods last year. These increases were mainly attributable to new assets coming into service, consistent with our ongoing capital work program as well as with an increase in costs to remove fixed assets associated with our capital projects. In addition, higher expenditures necessary to comply with Environment Canada's regulations on the removal of polychlorinated biphenyls increased the amortization of our related environmental regulatory asset. These increases were partially offset by the completion of amortization of a distribution regulatory account during the second quarter of this year.

Financing Charges

Financing charges increased by $3 million, or 4%, to $82 million in the third quarter and by $30 million, or 13%, to $255 million for the year-to-date period compared to last year. These increases primarily reflect a higher average level of debt, partially offset by a lower average effective interest rate. Lower capitalized interest also contributed to higher financing charges in the year-to-date period. Although we had higher levels of construction in progress, we capitalized less interest due to lower OEB-approved interest capitalization rates.

Provision for Payments in Lieu of Corporate Income Taxes

The provision for payments in lieu of corporate income taxes increased by $7 million, or 58%, to $19 million in the third quarter and by $13 million, or 33%, to $52 million on a year-to-date basis, compared to the same periods last year. The increases were primarily due to higher pre-tax income in the quarter and year-to-date periods, partially offset by a reduction in the statutory rate from 33.0% to 31.0%. These increases were partially offset in both periods by higher net temporary differences primarily related to pension costs, capitalized interest and other regulatory accounts, partially offset by higher future income taxes.

Net Income

Net income of $218 million in the third quarter and $492 million year-to-date was higher by $118 million and by $133 million, respectively, compared to 2009 results. Net income was higher in both periods as a result of higher average monthly peak demands due to unseasonably hot weather during the second and third quarters of this year, partially offset in the year-to-date period by milder weather during the winter months. Revenues were also impacted in both periods as a result of OEB-approved rate decisions that support investments in respect of supply mix policies, including the phase-out of coal-fired generation, necessary maintenance and investment requirements of our systems, and investments to address aging infrastructure. These investments in our transmission and distribution systems are signified by the increase of approximately $700 million in our fixed assets since the end of last year.

QUARTERLY RESULTS OF OPERATIONS

The following table sets forth unaudited quarterly information for each of the eight quarters from December 31, 2008 through September 30, 2010. This information has been derived from our unaudited interim Consolidated Financial Statements which, in the opinion of our management, have been prepared on a basis consistent with the audited annual Consolidated Financial Statements and which include all adjustments, consisting only of normal recurring adjustments, necessary for fair presentation of our financial position and results of operations for those periods. These operating results are not necessarily indicative of results for any future period and should not be relied upon to predict our future performance.

(Canadian dollars in millions)	2010				2009			2008
Quarter ended	**Sept. 30**	**Jun. 30**	**Mar. 31**	**Dec. 31**	**Sep. 30**	**Jun. 30**	**Mar. 31**	**Dec. 31**[2]
Total revenue[1]	1,360	1,165	1,319	1,207	1,144	1,090	1,303	1,194
Net income[1]	218	105	169	111	100	82	177	131
Net income to common shareholder[1]	214	100	165	106	96	77	173	126

[1] The demand for electricity generally follows normal weather-related variations, and therefore our electricity-related revenues and profit, all other things being equal, would tend to be higher in the first and third quarters than in the second and fourth quarters.

[2] As a result of the OEB's December 18, 2008 decision on Hydro One Networks' distribution rate application that was effective May 1, 2008, revenues in the fourth quarter of 2008 reflect a $25 million increase in respect of the period May 1, 2008 to December 31, 2008.

LIQUIDITY AND CAPITAL RESOURCES

Our primary sources of liquidity and capital resources are funds generated from operations, debt capital market borrowings and bank financing. These resources will be used to satisfy our capital resource requirements, which continue to include capital expenditures, servicing and repayment of our debt, payments related to our outsourcing arrangements, other investing activities, and dividends.

Summary of Sources and Uses of Cash	Three months ended September 30		Nine months ended September 30	
(Canadian dollars in millions)	**2010**	**2009**	**2010**	**2009**
Operating activities	414	285	958	658
Financing activities				
Long-term debt issued	500	300	1,500	900
Long-term debt retired	-	-	(400)	(400)
Short-term notes payable	-	(165)	(55)	60
Dividends paid	(4)	(26)	(23)	(161)
Investing activities				
Capital expenditures	(401)	(400)	(1,106)	(1,119)
Long-term investment	-	-	(250)	-
Other financing and investing activities	12	-	31	20
Net change in cash and cash equivalents	521	(6)	655	(42)

Operating Activities

Net cash from operating activities increased by $129 million, to $414 million in the third quarter, and increased by $300 million to $958 million in the first nine months, compared to 2009. These increases primarily reflect higher net income in both periods and changes to accounts payable balances in both periods due to increases such as our purchased power costs related to the demand for electricity, our pension liability as a result of the pension valuation filed in this quarter and increased taxes payable related to the implementation of the HST. These impacts on net cash were partially offset in the quarter by higher accounts receivable balances and in both periods, by changes to certain regulatory accounts.

Financing Activities

Short-term liquidity is provided through funds from operations, our Commercial Paper Program under which we are authorized to issue up to $1,000 million in short-term notes with a term to maturity of less than 365 days, our revolving credit facility and through our holdings of Province of Ontario Floating Rate Notes.

At September 30, 2010, we had no short-term notes outstanding. The Commercial Paper Program is supported by a total of $1,500 million in liquidity facilities comprised of a $1,250 million committed revolving credit facility with a syndicate of banks and the holding of $250 million of Province of Ontario Floating Rate Notes. The short-term liquidity under this program and anticipated levels of funds from operations should be sufficient to fund our normal operating requirements. During the second quarter, we increased the amount of our $500 million revolving credit facility, entered into in the first quarter, to $1,250 million and we extended the term of the facility to June 2013. In the second quarter we also cancelled the $750 million revolving credit facility which would have matured in August 2010.

At September 30, 2010, we had $7,975 million in long-term debt outstanding, including the current portion. Our notes and debentures mature between 2010 and 2046. Long-term financing is provided by our access to the debt markets, primarily through our Medium-Term Note (MTN) Program. On July 27, 2009, we filed a base shelf prospectus to renew our MTN Program for another 25 months. The maximum authorized principal amount of medium-term notes issuable under this program until August, 2011 is $3,000 million, of which $1,250 million was remaining and available as at September 30, 2010.

	Rating	
Rating Agency	**Short-term Debt**	**Long-term Debt**
DBRS Limited	R-1 (middle)	A (high)
Moody's Investors Service Inc.	Prime-1	Aa3
S&P	A-1	A+

We have the customary covenants normally associated with long-term debt. Among other things, our long-term debt covenants limit our permissible debt as a percentage of our total capitalization, limit our ability to sell assets and impose a negative pledge provision, subject to customary exceptions. The credit agreements related to our credit facilities have no material adverse change clauses that could trigger default. However, the credit agreements require that we provide notice to the lenders of any material adverse change within three business days of the occurrence. The agreements also provide

limitations that debt cannot exceed 75% of total capitalization and that debt issued by our subsidiaries cannot exceed 10% of the total book value of our assets. We are in compliance with all these covenants and limitations as of September 30, 2010.

In the year-to-date period of 2010, we issued $1,500 million in long-term debt under our MTN Program, including $500 million in the third quarter. We repaid $400 million in maturing long-term debt on a year-to-date basis, all in the second quarter. In 2009, we issued $300 million in long-term debt under our MTN Program in the third quarter, for a total of $900 million on a year-to-date basis. We repaid $400 million in maturing long-term debt in the first nine months of 2009, all in the first quarter. During the first nine months of this year, we reduced our short-term notes by $55 million, all in the first quarter. In 2009, we increased our short-term notes by $60 million in the first nine months, reflecting an increase of $225 million in the first two quarters of 2009 and a reduction of $165 million in the third quarter.

Common dividends are declared at the sole discretion of our Board of Directors, and are recommended by management based on results of operations, maintenance of the deemed regulatory capital structure, financial condition, cash requirements, and other relevant factors such as industry practice and shareholder expectations. Common dividends pertaining to the quarterly financial results are generally declared and paid in the immediately following quarter.

Consistent with the comparative periods in the prior year, we paid preferred dividends of about $4 million to the Province of Ontario (Province) in the third quarter and $13 million on a year-to-date basis. In 2010, we also paid common dividends of $10 million, all in the first three months of the year. In 2009, we paid common dividends of $22 million in the third quarter and $148 million on a year-to-date basis.

Our objectives with respect to our capital structure are to maintain effective access to capital on a long-term basis at reasonable rates, and to deliver appropriate financial returns. In order to ensure ongoing effective access to capital, we target to maintain an "A" category long-term credit rating.

Investing Activities

Cash used for investing activities primarily represents capital expenditures for each of our three business segments as follows:

	Three months ended September 30				Nine months ended September 30			
(Canadian dollars in millions)	**2010**	**2009**	**$ Change**	**% Change**	**2010**	**2009**	**$ Change**	**% Change**
Transmission	234	233	1	-	638	638	-	-
Distribution	165	166	(1)	(1)	465	477	(12)	(3)
Other	2	1	1	100	3	4	(1)	(25)
	401	400	1	-	1,106	1,119	(13)	(1)

Transmission

Transmission capital expenditures increased slightly by $1 million, to $234 million in the third quarter, and remained the same, at $638 million, in the first nine months, compared to the same periods in 2009.

Expenditures to expand and reinforce our transmission system were $142 million in the quarter and $353 million for the first nine months of the year, representing a decrease of $2 million and an increase of $6 million over the respective comparable periods. We continued to invest in a number of inter-area network upgrade projects to support the OPA's supply mix objectives for generation. We also continued to make investments in our local area supply projects to address growing loads. For the quarter, these expenditures were more than offset by a reduction in expenditures in our load and generation customer connection projects, a reduction in expenditures associated with local area supply projects that were substantially completed earlier this year, and the near completion of certain inter-area network projects.

Inter-area network upgrades with significant expenditures included the Bruce to Milton Transmission Reinforcement Project, to connect refurbished nuclear and new wind generation sources in the Huron-Grey-Bruce area, and the Northeast Transmission Reinforcement Project, which will increase the North-South interface transfer capability to access available northern generation. The Northeast Transmission Reinforcement Project is comprised of work to install static var compensators at Porcupine and Kirkland Lake Transformer Stations. In addition, we are installing static var compensators at Nanticoke and Detweiler Transformer Stations, which in the short-term will support increased generation from the Bruce

Nuclear facility and in the longer-term, will enhance the transfer capability between South Western Ontario and the Greater Toronto Area (GTA). These investments were partially offset by lower expenditures associated with the installation of capacitor banks in South Western Ontario. This equipment will provide interim protection to the Bruce Nuclear facility and will expand transmission capacity in South Western Ontario. In addition, we incurred lower expenditures associated with the Cherrywood Transformer Station to Claireville Transformer Station Connection Project, which will enable greater transfer capability across the GTA to accommodate power flows resulting from the new Hydro-Québec interconnection. This work is expected to be completed by the end of the year.

Local area supply projects with expenditures in the period include our Woodstock Area Transmission Reinforcement Project, which will increase capacity to ensure supply reliability in the Woodstock area, and our Switchyard Reconstruction Project at our Burlington Transformer Station, which will increase the load supply capacity to ensure reliability of supply to customers in the area. The GTA West Transmission Reinforcement Project, which has increased capacity to ensure supply reliability in the area, as well as the Hurontario Transformer Station to Jim Yarrow Municipal Transformer Station connection, which has increased transmission capacity in the Western Brampton area to allow for future load growth, were both substantially completed in the first quarter of this year, contributing to the reduction in expenditures in the third quarter compared to the prior year. The final completion of our Niagara Reinforcement Project continues to be delayed by the aboriginal land dispute in the Caledonia area. Discussions related to the Niagara Reinforcement Project continue between the aboriginal peoples involved and various government entities and we expect to complete this project when site access becomes available.

Expenditures to sustain our existing transmission system were $84 million in the quarter and $245 million on a year-to-date basis, representing increases of $15 million and $39 million respectively compared to the same periods last year. These increases are primarily due to increased expenditures related to the refurbishment and replacement of end-of-life lines and stations and to higher targeted replacements of aging components, specifically within our breaker installation program. We also experienced increased expenditures in the year-to-date period within our protection and control equipment program compared to the same period last year. These increased expenditures were partially offset in both periods by lower expenditures within our Spare Transformer Purchase and Hub Replacement Programs.

Our other transmission capital expenditures were $8 million in the quarter and $40 million for the first nine months, representing respective decreases of $12 million and $45 over the comparative periods. These reductions from the prior year were due to expenditures in 2009 on our investment in an entity-wide information system replacement and improvement project which replaced end-of-life systems and improved productivity, the second phase of which was completed during the third quarter of last year. Further impacting the year-to-date period are expenditures incurred to enhance information security at our Ontario Grid Control Centre which were lower compared to the same period in the prior year as we completed a number of enhancements to meet North American Electric Reliability Corporation requirements in 2009.

Distribution

Distribution capital expenditures decreased slightly by $1 million, or 1%, to $165 million in the third quarter and decreased by $12 million, or 3%, to $465 million for the first nine months, compared to the same periods in 2009.

Capital expenditures to expand and reinforce our distribution network were $82 million in the quarter and $231 million for the first nine months of the year, representing reductions of $2 million and $21 million over the comparable periods, respectively. We experienced reductions in both the quarter and year-to-date periods relating to expenditures on planned line development projects mainly due to a reallocation of resources to demand line work, particularly for line relocations. The reduction in the year-to-date period was also due to the substantial completion of smart meter installations across the province at the end of last year. In the quarter, the lower expenditures related to installations were offset by expenditures on the smart meter network infrastructure and the development and integration of the systems required for time-of-use billing, including meter reading capability and integration to the IESO meter data repository. Smart meter installations continued during the quarter as our total cumulative number of installations exceeded 1,301,000 as at September 30, 2010, thus nearing the program's total target. With over 731,000 meters enabled to support time of use billing as at September 30, 2010, we continue our efforts to migrate our customers to time-of-use pricing; over 271,000 of our customers are now consuming power based on time-of-use-pricing. Our program is one of the largest utility smart meter deployments in North America

Expenditures to sustain our distribution system of $74 million in the quarter and $212 million year-to-date, increased by $8 million and $36 million, respectively, compared to the same periods last year. These increases were primarily a result of higher expenditures on transport and work equipment and the planned replacement of end-of-life wood poles. In addition, we

experienced higher expenditures related to line relocation work in support of municipal road widening projects. In the year-to-date period, these increases were partially offset by lower storm-recovery expenditures.

Our other distribution capital expenditures were $9 million in the quarter and $22 million for the first nine months, representing respective reductions of $7 million and $27 million from the comparative periods. These reductions reflect our higher prior period investments in our entity-wide information system replacement and improvement project.

Future Capital Expenditures

Our capital expenditures for 2010 were originally budgeted at $2.0 billion. The 2010 capital budgets for our Transmission and Distribution Businesses were approximately $1,150 million and $850 million, respectively. Capital expenditures were expected to increase to approximately $2.1 billion in 2011 and approximately $2.2 billion in 2012. These expenditures reflected the sustainment requirements of our aging infrastructure budgeted at approximately $530 million in 2010, $620 million in 2011 and $670 million in 2012. Development projects, including inter-area network upgrades that reflect the OPA's supply mix policies to phase out coal generation and local area supply requirements, were budgeted at approximately $890 million in 2010, $780 million in 2011 and $550 million in 2012. These development investments also reflected the continued mass deployment of smart meters within our Distribution Businesses and the building of the required smart meter infrastructure in support of conservation objectives. We will leverage the smart meter investment to build a smart grid which will enhance our operations and support distributed generation. Other capital expenditures related to operations amounted to approximately $410 million in 2010, $290 million in 2011 and $230 million in 2012. Our capital expenditures to support the requirements under the Green Energy Act (GEA) were budgeted at approximately $190 million in 2010, $450 million in 2011 and $740 million in 2012. We are proceeding with our investments in support of the GEA that will need to be made to facilitate renewable generation consistent with the Feed-in-Tariff (FIT) program. Capital expenditures of our other business segment were budgeted at about $15 million in 2010, primarily reflecting the continued build out of the fibre optic network.

As a result of a number of factors, we now anticipate our expenditures for 2010, 2011 and 2012 to be in the range of $1.5 billion, $1.8 billion and $1.9 billion, respectively. These factors include delays and uncertainty regarding distributed generation requirements, reduced capital expenditures approved in recent rate decisions and filings, and the announcement on September 20, 2010 by the Minister of Energy that a Long-Term Energy Plan will be stakeholdered and developed into an Integrated Power System Plan to be reviewed by the OEB. This process could take until late 2011. As a result, we have deferred the Green Transmission projects for new lines in the absence of a Long-Term Energy Plan from the OPA. We will not undertake large capital expenditures without a reasonable expectation of recovering them in our rates. The anticipated expenditures for 2010 are comprised of approximately $900 million for our Transmission Business and $600 million for our Distribution Business.

Summary of Contractual Obligations and Other Commercial Commitments

The following table presents a summary of our debt and other major contractual obligations as well as other major commercial commitments.

September 30, 2010 (Canadian dollars in millions)	**Total**	**2010[1]**	**2011/2012**	**2013/2014**	**After 2014**
Contractual Obligations *(due by year)*					
Long-term debt – principal repayments	7,975	200	1,100	1,350	5,325
Long-term debt – interest payments	6,744	145	788	668	5,143
Inergi LP (Inergi) outsourcing agreement[2]	605	36	282	265	22
Operating lease commitments	55	2	13	13	27
Environmental obligations[3]	376	11	68	79	218
Total Contractual Obligations	15,755	394	2,251	2,375	10,735
Other Commercial Commitments *(by year of expiry)*					
Bank line[4]	1,250	-	-	1,250	-
Letters of credit[5]	108	107	1	-	-
Guarantees[5]	326	326	-	-	-
Pension[6]	343	51	280	12	-
Total Other Commercial Commitments	2,027	484	281	1,262	-

[1] The amounts disclosed represent the balances due over the period October 1, 2010 to December 31, 2010.

[2] On May 1, 2010, the Company extended the Master Services Agreement (MSA) with Inergi for a further three-year period. The term of the agreement, which would have expired on February 29, 2012, has been extended to February 28, 2015. Under the extended agreement, Inergi will provide business processing and information technology outsourcing services, as well as core system support related primarily to SAP implementation and optimization. The amounts disclosed include an estimated annual inflation adjustment in the range of 1.8% to 3.0%.

[3] We record a liability for the estimated future expenditures associated with the phase-out and destruction of polychlorinated biphenyl contaminated insulating oil from electrical equipment and for the assessment and remediation of contaminated lands. The expenditure pattern reflects our planned work program for the period.

[4] As a backstop to our commercial paper program, we have a $1,250 million revolving standby credit facility with a syndicate of banks which matures in June 2013.

[5] We currently have bank letters of credit of $107 million outstanding relating to retirement compensation arrangements (RCAs). The other $1 million included in letters of credit pertains to operating letters of credit. On November 1, 2010, we increased our letters of credit relating to RCAs to approximately $113 million. We have also provided prudential support to the IESO on behalf of our subsidiaries as required by the IESO's Market Rules, using parental guarantees of up to a maximum of $325 million and on behalf of two distributors using guarantees of up to a maximum of $660 thousand. Although no letters of credit are required for prudential support, we would have to resume providing bank letters of credit if our credit rating deteriorated to below the "Aa" category.

[6] Contributions to the pension fund are made one month in arrears. Contributions for 2010, 2011 and 2012 will be based on an actuarial valuation effective December 31, 2009. Based on current factors, we currently estimate our pension contributions to be approximately $140 million annually starting in 2010, and variable in 2011 and 2012 based on the level of pensionable earnings. Contributions for 2013 will be based on an actuarial valuation effective December 31, 2012 and will depend on future investment returns, changes in benefits or actuarial assumptions.

The principal amounts in the above table under long-term debt are not charged to our results of operations, but are reflected on our Balance Sheet and Statement of Cash Flows. Interest associated with this debt is recorded under financing charges on our Statement of Operations or in our capital programs. Payments in respect of operating leases and our outsourcing agreement with Inergi are recorded under operation, maintenance and administration costs on our Statement of Operations or in our capital programs.

RELATED PARTY TRANSACTIONS

Related party transactions primarily consist of our transmission revenues received from, and our power purchase payments made to, the IESO, which is a related party by virtue of its status as an agency of our shareholder, the Province. The year-over-year changes related to these amounts are described more fully in our discussion of our transmission revenues and purchased power costs. Other significant related party transactions include our dividends, which are paid to the Province and our payments in lieu of corporate income taxes, which are paid or payable to the Ontario Electricity Financial Corporation. In January 2010, we purchased $250 million Province of Ontario Floating Rate Notes, maturing on November 19, 2014 as a form of alternate liquidity to supplement our bank credit facilities.

CONSIDERATIONS OF CURRENT ECONOMIC CONDITIONS

Pension

During the first nine months of 2010, the deferred pension asset reported on our balance sheet decreased by $48 million to $376 million. We contributed $89 million into our pension plan and incurred $137 million in net periodic pension benefit cost. Contributions for 2010, 2011 and 2012 will be based on an actuarial valuation effective December 31, 2009 filed in September of this year. Based on current factors, we currently estimate our pension contributions to be approximately $140 million annually starting in 2010, with some variation in 2011 and 2012 based on the level of pensionable earnings. Contributions for 2013 will be based on an actuarial valuation effective December 31, 2012 and will depend on future investment returns, changes in benefits and actuarial assumptions.

Our pension plan experienced a positive return of 7.42% in the third quarter, bringing the year-to-date return to 4.60%. Consistent with other pension plans, our pension plan could be negatively impacted in the fourth quarter of this year as a result of the current economic uncertainty and financial market volatility, as was experienced by the plan in the second quarter of this year. However, our fund recovered in the third quarter to experience a positive return on a year-to-date basis as at September 30, 2010.

The pension fund has broad exposure from its investments in domestic and international equity markets, as well as in fixed income markets. The overall exposure of the fund reflects its holdings across a number of sectors, and a well-diversified portfolio to support long-term objectives.

We continue to monitor our financial risks, including credit risk.

STATUS OF OUR TRANSITION TO INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRS)

On February 13, 2008, the Canadian Accounting Standards Board (AcSB) confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian generally accepted accounting principles (GAAP) for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011, with comparative data also reported under IFRS. In anticipation of this decision, we commenced our IFRS conversion project in 2007.

The project has four separate phases: diagnostic, design and planning, solution development, and implementation. We completed the diagnostic phase in 2008. It involved a high level review and identification of the major differences between current GAAP and IFRS in all subject areas resulting in the identification of the areas of accounting difference with the highest potential to significantly impact our company.

In 2009, we completed the design and planning and the solution development phases of our project, including substantial completion of all our policy analyses. We are currently engaged in the implementation phase which is the final phase of our project. We are preparing to begin tracking our comparative results under IFRS next year. We are concurrently developing plans to support accounting and business processes should rate-regulated accounting be discontinued. Our teams continue to monitor progress relative to key milestones, monitor developments of both the International Accounting Standards Board (IASB or the Board) and the AcSB, update recommendations and develop financial reports. We continue to have recurring dialogue with our external auditors about possible outcomes of our project.

We continue to evaluate the impacts of current and prospective IFRS on all of our business activities, including those of our subsidiaries and the impact on our entity-wide information system. We are simultaneously analyzing the impacts of changes on our disclosure controls and internal controls over financial reporting, our debt covenants and our performance measures. We continue to provide formal communications to our employees. We have completed numerous staff training sessions and will plan for future training sessions as standards continue to evolve.

Accounting Policies

During 2009, both the Public Sector Accounting Board (PSAB) and the Canadian Securities Administrators' (CSA) staff confirmed that companies such as Hydro One will be required to adopt IFRS in 2011. On December 14, 2009, the PSAB issued an exposure draft proposing to remove the requirement for government organizations adhering to IFRS to also apply additional public sector financial reporting standards, currently Public Sector Accounting Handbook Section 3270. The effective date for the proposed changes is January 1, 2011.

The areas with the highest potential to significantly impact our company upon conversion to IFRS, identified during the diagnostic phase, are regulatory assets and liabilities, fixed assets, payments in lieu of corporate income taxes, employee future benefits, as well as initial adoption of IFRS under the provisions of IFRS 1, *First-Time Adoption of IFRS* (IFRS 1). The IASB's project on rate-regulated activities (RRA) will have an impact on the accounting choices available in all of these areas.

In December 2008, the IASB added a project on RRA to its agenda. In July 2009, the IASB issued an exposure draft detailing its proposals for standards for the accounting of RRA. The exposure draft allowed for the continued recognition of regulatory assets and liabilities on the Balance Sheet. In-scope assets and liabilities were proposed to be carried at the net present value of the expected future cash flows. The exposure draft made an exception to the requirements of other IFRS standards by allowing capitalization of otherwise ineligible costs within fixed assets and intangible assets on the basis of the inclusion of these costs in rate base. The IASB requested comments from interested observers on the exposure draft. We responded to the IASB's request for comment on November 24, 2009. The IASB received approximately 150 responses to its request for comment, which were very diverse in their opinions. As a result, the IASB staff postponed presenting their analysis of the responses to the IASB, originally scheduled for January, to the Board's February meeting. The presentation to the IASB in February included options for the next steps of the project.

The Board decided tentatively to finalize the transition relief for first-time adopters. The transition relief proposed offers an optional exemption for a first-time adopter with RRA to use the carrying amount of fixed assets or intangible assets as deemed cost on the transition date when the carrying amount includes costs that would not otherwise qualify for capitalization. On May 6, 2010, the IASB issued the omnibus *Improvements to IFRSs*, which included the expected amendment to IFRS 1 applicable to entities with RRA. We expect to elect this exemption for our regulated businesses.

The IASB directed its staff to continue its research and analysis and to focus on the key issue of whether regulatory assets and liabilities exist in accordance with the current IFRS framework and whether they are consistent with other standards. The IASB met twice on July 20 and July 22, 2010 to further discuss the proposals of the rate-regulated accounting project. The IASB did not arrive at any decision and decided to continue its analysis and outreach activities on the project. Subsequently, the AcSB met on July 23, 2010 and decided to propose an interim relief for rate-regulated entities by permitting them to defer their IFRS implementation date to January 1, 2013. The AcSB released an exposure draft on July 28, 2010, to which Hydro One responded. On September 10, 2010, after further deliberation, the AcSB decided to reduce the relief period by permitting rate-regulated entities to defer their IFRS implementation date to January 1, 2012. We plan on adopting the one-year deferral. On September 16, 2010, the IASB met to continue its discussions on its project on RRA. The IASB did not reach any conclusions during this meeting. Instead, it decided to include in its public consultation a request for views on what form a future project might take, if any, to address RRA. The feedback will assist the IASB in setting its future agenda. The form that the project will take is uncertain at this time, as is the outcome. At this time, there is also uncertainty as to how the OEB will respond.

We will continue to assess the IASB's deliberation on the project. At the same time, we are currently assessing, through review with our auditors, whether any of our regulatory accounts could be recognized under the current IFRS framework. If rate-regulated accounting were not permitted and none of our regulatory accounts were determined to fall under the current IFRS framework, the write-off of our regulatory assets and regulatory liabilities would result in a net reduction to retained earnings of approximately $339 million as at December 31, 2009. Regulatory accounting affects the timing of the accounting recognition of costs, revenues, losses and gains. Therefore, to the extent that we may be unable to recognize regulatory assets and liabilities after implementing IFRS in 2012, our statement of operations may be impacted by a change in the timing of recognition of these amounts in our statement of operations.

In-Progress Construction and Development

Current IFRS are significantly different from Canadian GAAP in terms of the expenditures that can be capitalized to in-progress construction and development programs and projects. Certain fixed asset and intangible asset expenditures are ineligible for capitalization under IFRS. In the absence of rate-regulated accounting, the estimated impact on our financial statements would have been a reduction of approximately $275 million in capital expenditures and an increase of approximately $275 million in operations, maintenance and administration expenditures had this accounting been followed in 2009.

Employee Future Benefits

Given that the RRA project has not been finalized at this point, it is unclear at this time whether the continuation of accounting for expenditures related to employer-sponsored pension plans on a cash basis would be permissible. Regulatory assets and liabilities, representing the cumulative difference between our company's pension contributions accounted for on a cash basis at the direction of the regulator, and the costs that would be recognized on an accrual basis under Canadian GAAP, may not meet the definition of assets or liabilities under IFRS and hence may require de-recognition at the IFRS transition date. Similarly, we are assessing our options with respect to the recognition of accumulated, unamortized actuarial gains and losses associated with employment benefits. Currently, the possible alternatives to account for these pension and other employee benefit amounts include charging unamortized actuarial gains and losses immediately upon adoption under IFRS 1 or recognizing an adjustment to those amounts retrospectively to comply with IAS 19, *Employee Benefits*. Our policy choice may be contingent upon the outcome of the RRA project. The impact of using IFRS 1 as at December 31, 2009 would be a change to retained earnings of $852 million.

In April 2010, the IASB published an exposure draft, *Defined Benefit Plans (Proposed amendments to IAS 19 Employee Benefits)*, with significant implications for both financial position and income reporting. Deferred recognition of actuarial gains and losses would be eliminated and instead all changes in the defined benefit obligation and in the fair value of plan assets would be recognized in the statement of comprehensive income when those changes occur. The exposure draft also proposed a new presentation approach where the changes in the defined benefit obligation and the fair value of plan assets would be segregated and separately disclosed as service cost, finance cost and re-measurement adjustments. Service cost and

finance cost components would be recognized in the statement of operations. The re-measurement adjustments representing actuarial gains and losses would be recognized as part of other comprehensive income. As per the IASB's revised timeline, the final standard is expected in the first quarter of 2011 with an effective date not earlier than 2013. The new accounting standard when adopted in 2013 or in later years will result in higher volatility in the statement of comprehensive income due to the recognition of the full amount of actuarial gains and losses.

Payments in Lieu of Corporate Income Taxes

We recognize future tax assets and liabilities in accordance with Canadian Institute of Chartered Accountants Handbook section 3465, *Income Taxes*, which was amended effective January 1, 2009 to bridge the convergence to IFRS. As such, we have determined that there is no potential for a significant impact for this class of transactions based upon contingent outcomes regarding transactions for payments in lieu of corporate income taxes. If the RRA project is adopted as is, we plan to continue to record taxes on a cash basis instead of the liability method for the regulated businesses. Currently, we expect to record differences in items credited or charged directly to equity, financial instruments and unused tax losses and unused tax credits. If rate-regulated accounting is not permitted, the impact on our provision for payments in lieu of corporate income taxes would be recognized using the liability method and there would be no regulatory accounts established for taxes to be recovered through future rates. As a result the provision for PILs as at December 31, 2009 would have been lower by approximately $46 million including the impact of a change in substantively enacted tax rates.

OEB Consultation

In May 2008, the OEB initiated a consultative process to determine the nature of any changes to regulatory reporting requirements in response to IFRS. The OEB held public meetings and a formal stakeholder conference in May 2009. We participated at each opportunity offered to the public to communicate with the OEB. On July 28, 2009, the OEB released some preliminary views on how regulatory reporting requirements will change in response to IFRS. The OEB has initiated a second phase of its consultative process to amend certain regulatory instruments. We are continuing to assess the impact of the OEB's report and other recommendations on our IFRS conversion project.

On February 24, 2010, the OEB issued a letter to all licensed electricity distributors and rate-regulated natural gas utilities for the purpose of clarifying the OEB's view released in July on accounting for overhead costs in the cost of new capital works effective January 1, 2011. The OEB stated in the letter that it would be requiring full compliance with IFRS requirements, including those in IAS 16, *Property, Plant and Equipment* (IAS 16), as applicable to non-regulated enterprises and only where the OEB authorizes specific alternative treatment for regulatory purposes is alternative treatment acceptable. We continue to assess this guidance in light of our rate applications and the AcSB's revised implementation date.

On November 8, 2010, the OEB published an amendment to a report it made on its policy, *Transition to International Financial Reporting Standards*. In response to the AcSB allowing rate-regulated entities the option to delay their adoption of IFRS to January 1, 2012, the OEB has adjusted certain policy statements in the report to account for this choice.

Internal Control over Financial Reporting and Disclosure Controls and Procedures

We are continuously analyzing the impacts of changes on our disclosure controls and procedures and internal controls over financial reporting as we proceed through our implementation of IFRS. Additional disclosure controls may be required to address first time adoption and additional internal controls may be required to implement changes in our accounting policies and to support our ongoing IFRS reporting requirements. Required changes to our control environment cannot be determined until such time as policy choices are finalized.

We have initiated the process of analyzing our current disclosure control and procedure and internal control documentation to identify changes required upon the adoption of IFRS. We have categorized each control process as low, medium or high-impact, based on the currently assessed risk of a major change being required upon implementation of IFRS. This ranking was completed in the fourth quarter of 2009. We completed updating the documentation for all of the low and medium-risk processes with IFRS implementation impact, including process documentation and risk and control matrices, during the second quarter. Completion of our documentation revisions for our high-risk processes had been put on hold pending a decision from the IASB on their RRA project due to the impact that would have on these processes. With the future of the RRA project unclear at this time, we are currently assessing how regulatory accounting fits into the current IFRS framework. Once we conclude on the impact of the absence of guidance within IFRS on rate-regulated accounting, we will begin to assess the impact that will have on our high-risk processes. Once our high-risk process documentation has been updated, we

will begin walkthroughs of all of our revised process and control documentation for low, medium and high-risk processes. At this time we estimate that we will complete this on a timely basis for reporting under IFRS in 2012.

Financial Reporting Expertise

The project's formal governance structure includes a steering committee consisting of senior level management from finance, information technology, treasury and our operations organizations. Project status reporting is provided to senior executive management and to the Audit and Finance Committee of our Board of Directors on a quarterly basis, or more often as necessary.

The training of key finance and operational staff commenced in 2007 and has been on-going. Training has also been given to the Audit and Finance Committee and senior executive management to communicate the key differences between Canadian GAAP and IFRS, and to provide them with an overview of the key impacts conversion could have on our financial statements. These groups are updated as developments in IFRS continue. Due to the extensive staffing requirements associated with such a large-scale project, an external expert advisor was engaged to assist with our IFRS conversion project, from the planning phase through to implementation.

The Audit and Finance Committee and senior management continue to be updated for key developments in IFRS and their potential impact on our financial statements. Updates are provided on at least a quarterly basis. This will continue through to our conversion to IFRS in 2012. During the third quarter we continued to provide training to our key finance and operational staff. To date, they have been trained in many key areas including property, plant and equipment, regulatory accounting, revenue recognition, liabilities, employee benefits, financial instruments and most recently income taxes. In addition to sessions on specific topics, we have also held one financial reporting update session. During the next year, we will continue to provide IFRS financial reporting update sessions on a regular basis beginning with one further training session scheduled for the fourth quarter of this year.

Business Activities

The company has the customary covenants normally associated with long-term debt. Among other things, our long-term debt covenants limit our permissible debt as a percentage of our total capitalization. Depending on the outcome of various exposure drafts under IFRS, we could undergo changes to our results that would impact our debt covenants. For example, covenants would be impacted as a result of de-recognition of regulatory assets and liabilities, accounting for expenditures related to employer-sponsored pension plans on an accrual basis versus a cash basis and the change in costs that are allowable versus disallowable for capitalization as part of the cost of self-constructed assets. As part of our IFRS transition project, we have been analyzing the impacts of potential changes in accounting policy on our debt covenant and communicating potential scenarios and impacts analyses to our Audit and Finance Committee. Based on our calculations, we would remain in compliance with our debt covenants. However, we met with our financial institutions and amended our credit agreement with the syndicate of banks to consider the potential impacts that IFRS may have on our covenants. Specifically, the calculation of our debt to total capitalization ratio was modified under this agreement for certain items to factor IFRS impacts, such that the debt to total capitalization ratio is representative of what it was prior to IFRS. The same ratio is used to support the indenture agreement with our bondholders. Given our calculations, the indenture agreement was not updated at that time because we estimated that we would remain within the threshold for our debt to capitalization ratio given the information available at the time. We have continued to monitor the impact of conversion on our debt covenants as IFRS develops and as we finalize our policy choices under IFRS. With the recent deferral of the IASB RRA project, we intend to re-assess the impact on our debt to capitalization ratio and identify appropriate next steps.

Information Technology (IT) Systems

As part of an entity-wide system improvement project, many of our major financial systems were replaced in 2008 and 2009. To ensure that the future requirements of IFRS would be met, common team members were included within the governance structure of our IFRS project and the new entity-wide system implementation team. At the same time, members of the IFRS implementation team were involved in the design of our new entity-wide system. IT implications were identified and assessed during our diagnostic and design and planning stages of our IFRS project and were incorporated in the project's solution development stage. For example, the new system has been configured to track depreciation on a component level, based on the useful life of the asset, as currently required under IAS 16. The new system has also been configured to track allowable versus disallowable costs for capitalization under IAS 16. The system has been designed with the maximum flexibility given the uncertainty of rate-regulated accounting under the IASB's current project. Given the recent decision by

the AcSB to defer implementation, we are currently making the required changes to continue reporting under Canadian GAAP until January 1, 2012. We are currently on track to have our systems ready to report under IFRS beginning on January 1, 2012, with comparatives.

DISCLOSURE CONTROLS AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

In 2008, we began transitioning our major financial systems to a SAP enterprise-wide platform as part of the entity-wide information system replacement and improvement project. A formal project governance structure was put in place to ensure an effective transition of the information technology systems and business processes. The governance structure included a steering committee consisting of senior levels of management which reports to senior executive management and the Business Transformation Committee of the Board of Directors.

In 2008, we successfully implemented the first phase of the supply chain, asset and work management modules in SAP. In 2009, we successfully implemented various Finance, Human Resources, Payroll and Investment Management modules. The reporting tool Business Intelligence/Business Warehouse was also implemented. This implementation included new controls over Internal Controls over Financial Reporting and the replacement of other controls in the previous environment. Our process documentation has been updated and the design and effectiveness of the controls have been tested.

In compliance with the requirements of National Instrument 52-109, *Certification of Disclosure in Issuers' Annual and Interim Filings*, our Certifying Officers have reviewed and certified the Consolidated Financial Statements for the interim period ended September 30, 2010, together with other financial information included in our quarterly securities filings. Our Certifying Officers have certified that disclosure controls and procedures have been designed to provide reasonable assurance that material information relating to our company is made known within our company. Further, our Certifying Officers have also certified that internal controls over financial reporting have been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements.

RECENT DEVELOPMENTS

Long-Term Energy Plan

The Ontario Government (the Government) announced in September 2010 that it intends to update Ontario's Long-Term Energy Plan, and has requested input from Ontarians as it undertakes this initiative. Once the Long-Term Energy Plan is updated, we will re-assess our capital work program.

Policy on Transmission Project Development Planning

The OEB issued a policy paper on August 26, 2010, *Framework for Transmission Project Development Plans*, which provides for a competitive bidding process on enabler facilities and network expansion projects. The policy describes how project development planning will work in conjunction with existing OEB processes for licensed transmitters.

Renewed Regulatory Framework for Electricity

On October 27, 2010, the OEB announced that it is renewing its regulatory framework to reflect the importance of future network investments. The renewed regulatory framework will be developed through three policy initiatives. First, the OEB will re-examine its approach to network investment planning by transmitters and distributors, including an examination of ways to encourage distributors and transmitters to plan their investments with the total bill impact in mind. Second, it will review its rate mitigation policy by examining alternative approaches and rate treatments that might smooth the impact to consumers of rate or bill increases. Third, it will review its current rate-making policies to ensure that they continue to facilitate the cost-effective and efficient implementation of OEB-approved plans. In conjunction with the development of these three policy initiatives, the OEB has extended the third generation IRM plan.

Status of Rate Applications

The oral hearing for our subsidiary Hydro One Network Inc.'s application for 2011 and 2012 transmission rates concluded on October 7, 2010. An OEB decision is anticipated in January 2011. The application seeks the approval for a revenue

requirement of approximately $1,446 million and $1,547 million for 2010 and 2011, respectively. This represents an estimated increase in rates of 15.7% and 9.8%, respectively, or 1.2% and 0.7% on an average customer's monthly bill.

On June 30, 2010, our subsidiary, Hydro One Brampton Networks Inc. (Hydro One Brampton), filed its application for 2011 rates. On September 2, 2010, Hydro One Brampton requested an amendment to its application to reflect the AcSB's decision to allow the deferral of IFRS implementation for rate-regulated entities to January 1, 2012, as well as the Ontario Municipal Employees Retirement System's announcement regarding increases in pension plan premiums affecting 2011. The revised application seeks approval for a revenue requirement of approximately $63 million. Combined with the impact of rate riders, this represents an estimated increase in distribution rates of approximately 7.5%, or an increase of about 2.3% on an average customer's monthly bill. A hearing is expected to take place in December, with a decision anticipated early in 2011.

On October 15, 2010, our subsidiary, Hydro One Remote Communities, filed its application for 2011 distribution rates under the OEB's third generation IRM. The application seeks OEB approval for a rate increase of approximately 0.4%. A decision is anticipated in March 2011.

Request for Distribution System Code (DSC) Exemption

On June 30, 2010, Hydro One Networks Inc. filed an application with the OEB requesting an exemption for certain Distributed Generation projects from specific sections of the DSC pertaining to cost responsibilities for electricity generators. An oral hearing took place on October 6, 2010. A decision is pending.

CDM Code for Electricity Distributors

On September 16, 2010, the OEB issued the conservation and demand management code for electricity distributors. The new code clarifies the CDM strategy, annual reporting requirements, accounting treatment and performance incentive payments. The treatment of lost revenues resulting from CDM programs will be determined by the OEB and communicated to distributors at a future date. On November 1, 2010, in compliance with the code, we submitted our CDM strategy identifying how we plan to reach our mandatory targets. The strategy will be reviewed by the OEB for compliance with the CDM Code.

Debt Issues

On September 13, 2010, we issued $250 million of notes at a coupon rate of 2.95% and with a maturity date of September 11, 2015. On the same date, we issued an additional offering of $250 million of notes at a coupon rate of 5.00% maturing on October 19, 2046, originally issued on October 19, 2006. The total amount outstanding for that issue is now $325 million.

SELECTED FINANCIAL HIGHLIGHTS AND RATIOS

	Three months ended September 30		Nine months ended September 30	
(Canadian dollars in millions) (except as otherwise noted)	**2010**	**2009**	**2010**	**2009**
Net income	218	100	492	359
Net cash from operating activities	414	285	958	658
Capital expenditures	401	400	1,106	1,119
Basic and fully diluted earnings per common share *(Canadian dollars)*	2.134	949	4.790	3.454
Earnings coverage ratio[1]			2.45	2.36
Net asset coverage on long-term debt[2]			1.74	1.79
Total debt to capitalization[3]			58%	56%

[1] The earnings coverage ratio has been presented for the twelve months ended September 30, 2010 and September 30, 2009, respectively and has been calculated as the sum of net income, provision for payments in lieu of corporate income taxes and financing charges divided by the sum of financing charges, capitalized interest and cumulative preferred dividends.

[2] The net asset coverage on long-term debt ratio has been presented as at September 30, 2010 and December 31, 2009 and has been calculated as total assets minus total liabilities excluding long-term debt (including current portion) divided by long-term debt (including current portion).

[3] Total debt to capitalization ratio has been presented as at September 30, 2010 and December 31, 2009 and has been calculated as total debt divided by total debt plus total shareholder's equity.

FORWARD-LOOKING STATEMENTS AND INFORMATION

Our oral and written public communications, including this document, often contain forward-looking statements that are based on current expectations, estimates, forecasts and projections about our business and the industry in which we operate and include beliefs and assumptions made by the management of our company. Such statements include, but are not limited to: expectations regarding energy-related revenues and profit; expectations regarding developments in the statutory, regulatory and operating framework for electricity distribution and transmission in Ontario including amendments to codes, statements related to new codes and the impact of new regulatory guidelines and decisions from the OEB and other governing bodies; statements related to the status of our rate applications and rate changes including estimated rate increases and expected impacts on an average customer's bill; statements regarding our future liquidity and capital resource requirements; expectations regarding our financing activities including our targeted long-term credit rating; expectations regarding the results of our on-going and planned projects and/or initiatives and their completion dates; statements regarding future capital expenditures, budgets and our investment plans; statements related to smart meters, time-of-use pricing and the associated smart grid; statements regarding contractual obligations and other commercial commitments; statements regarding future pension contributions and our pension plan; and statements related to IFRS, the IASB, the AcSB, our conversion to IFRS, planned courses of action, and expected impacts in the event of a discontinuance of regulatory accounting. Words such as "expect", "anticipate", "intend", "attempt", "may", "plan", "will", "believe", "seek", "estimate", "goal", "aim", "target", and "continue", and variations of such words and similar expressions, are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. We do not intend, and we disclaim any obligation to update any forward-looking statements, except as required by law.

These forward-looking statements are based on a variety of factors and assumptions including, but not limited to the following: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; no unfavourable decisions from the OEB and other regulatory bodies concerning outstanding rate and other applications; no unforeseen changes in rate orders or rate structures for our distribution and transmission businesses; a stable regulatory environment; the preparation of business plans, comparative numbers, regulatory filings and future capital expenditures on the basis that rate-regulated accounting will continue to exist under IFRS; and no significant event occurring outside the ordinary course of business. These assumptions are based on information currently available to us, including information obtained from third-party industry analysts. Actual results may differ materially from those predicted by such forward-looking statements. While we do not know what impact any of these differences may have, our business, results of operations, financial condition and our credit stability may be materially adversely affected. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things:

- the risks associated with being controlled by the Province;
- the impact of the final outcome of the exposure draft on rate-regulated accounting;
- on-going discussions with the OPA regarding transmission project needs and priorities and distributed generation requirements;
- the impact of the Ontario Government's Long-Term Energy Plan on our capital work program;
- any opposition to and delays or denials of the requisite approvals and accommodations for our planned projects;
- the result of regulatory decisions regarding our revenue requirements, cost recovery and rates;
- investment returns, changes in benefits or actuarial assumptions;
- the risks related to the current economic uncertainty and financial market volatility;
- the risk that previously granted regulatory approvals may be subsequently challenged, appealed or overturned; and
- the impact of the GEA on our company and the costs and expenses arising there from.

We caution the reader that the above list of factors is not exhaustive. Some of these and other factors are discussed in more detail under "Risk Management and Risk Factors" in the 2009 annual Management's Discussion and Analysis (MD&A). You should review the section entitled "Risk Management and Risk Factors" in detail.

This MD&A is dated as at November 11, 2010. Additional information about our company, including our Annual Information Form, is available on SEDAR at www.sedar.com.

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (unaudited)

(Canadian dollars in millions)	Three months ended September 30 2010	2009	Nine months ended September 30 2010	2009
Revenues				
Transmission	376	296	1,002	869
Distribution	970	831	2,795	2,620
Other	14	17	47	48
	1,360	1,144	3,844	3,537
Costs				
Purchased power	638	547	1,835	1,731
Operation, maintenance and administration	253	267	777	791
Depreciation and amortization	150	139	433	392
	1,041	953	3,045	2,914
Income before financing charges and provision for payments in lieu of corporate income taxes	319	191	799	623
Financing charges *(Note 6)*	82	79	255	225
Income before provision for payments in lieu of corporate income taxes	237	112	544	398
Provision for payments in lieu of corporate income taxes *(Note 11)*	19	12	52	39
Net income	218	100	492	359
Other comprehensive loss	-	-	-	-
Comprehensive income	218	100	492	359
Basic and fully diluted earnings per common share *(Canadian dollars)*	2.134	949	4.790	3.454

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS (unaudited)

(Canadian dollars in millions)	Three months ended September 30 2010	2009	Nine months ended September 30 2010	2009
Retained earnings, beginning of period	2,046	1,633	1,791	1,497
Change in accounting policy for the recognition of future income tax assets and liabilities *(Note 2)*	-	-	-	12
Net income	218	100	492	359
Dividends *(Note 3)*	(4)	(26)	(23)	(161)
Retained earnings, end of period	2,260	1,707	2,260	1,707

CONSOLIDATED STATEMENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME (unaudited)

(Canadian dollars in millions)	Three months ended September 30 2010	2009	Nine months ended September 30 2010	2009
Accumulated other comprehensive income, beginning of period	(10)	(10)	(10)	(10)
Other comprehensive loss	-	-	-	-
Accumulated other comprehensive income, end of period	(10)	(10)	(10)	(10)

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS (unaudited)

(Canadian dollars in millions)	September 30, 2010	December 31, 2009
Assets		
Current assets:		
Short-term investments	656	-
Accounts receivable (net of allowance for doubtful accounts)	856	843
Regulatory assets	62	72
Materials and supplies	21	21
Future income tax assets	23	21
Other	16	16
	1,634	973
Fixed assets:		
Fixed assets in service	19,094	18,407
Less: accumulated depreciation	7,130	6,815
	11,964	11,592
Construction in progress	1,624	1,256
Future use land, components and spares	138	150
	13,726	12,998
Other long-term assets:		
Regulatory assets *(Note 11)*	1,002	858
Deferred pension asset	376	424
Intangibles (net of accumulated amortization)	196	218
Goodwill	133	133
Future income tax assets	19	18
Other assets	19	13
Long-term investment *(Note 4)*	249	-
	1,994	1,664
Total assets	17,354	15,635

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS (unaudited) (continued)

(Canadian dollars in millions)	September 30, 2010	December 31, 2009
Liabilities		
Current liabilities:		
Bank indebtedness	27	26
Accounts payable and accrued charges	847	800
Regulatory liabilities *(Note 5)*	83	100
Accrued interest	125	74
Short-term notes payable	-	55
Long-term debt payable within one year *(Note 6)*	450	600
	1,532	1,655
Long-term debt *(Note 6)*	7,537	6,281
Other long-term liabilities:		
Employee future benefits other than pension	974	940
Regulatory liabilities *(Note 5)*	443	489
Future income tax liabilities *(Note 11)*	678	533
Environmental liabilities	290	303
Long-term accounts payable and other liabilities	13	16
	2,398	2,281
Total liabilities	11,467	10,217
Shareholder's equity		
Preferred shares (authorized: unlimited; issued: 12,920,000)	323	323
Common shares (authorized: unlimited; issued: 100,000)	3,314	3,314
Retained earnings	2,260	1,791
Accumulated other comprehensive income	(10)	(10)
Total shareholder's equity	5,887	5,418
Total liabilities and shareholder's equity	17,354	15,635

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)

(Canadian dollars in millions)	Three months ended September 30		Nine months ended September 30	
	2010	**2009**	**2010**	**2009**
Operating activities				
Net income	218	100	492	359
Environmental expenditures	(5)	(4)	(13)	(7)
Adjustments for non-cash items:				
Depreciation and amortization (excluding removal costs)	130	124	387	355
Retail settlement variance accounts	(11)	-	11	(3)
Special purpose charge *(Note 5)*	3	-	(7)	-
Regulatory liability refund account	(7)	(7)	(21)	(17)
Future income taxes	2	3	15	8
Smart meters	(2)	-	(13)	(1)
Rider 6 *(Note 5)*	(4)	(5)	(7)	(20)
Other regulatory asset and liability accounts	(10)	5	(9)	9
Amortization of debt costs	(1)	-	1	-
Rural and remote rate protection variance account	7	2	15	(7)
	320	218	851	676
Changes in non-cash balances related to operations	94	67	107	(18)
Net cash from operating activities	414	285	958	658
Financing activities				
Long-term debt issued	500	300	1,500	900
Long-term debt retired	-	-	(400)	(400)
Short-term notes payable	-	(165)	(55)	60
Dividends paid	(4)	(26)	(23)	(161)
Other	-	(2)	-	3
Net cash (used in) from financing activities	496	107	1,022	402
Investing activities				
Capital expenditures				
Fixed assets	(401)	(373)	(1,097)	(1,039)
Intangible assets	-	(27)	(9)	(80)
	(401)	(400)	(1,106)	(1,119)
Long-term investment	-	-	(250)	-
Other assets	12	2	31	17
Net cash used in investing activities	(389)	(398)	(1,325)	(1,102)
Net change in cash and cash equivalents	521	(6)	655	(42)
Cash and cash equivalents, beginning of period *(Note 8)*	108	(20)	(26)	16
Cash and cash equivalents, end of period	629	(26)	629	(26)

See accompanying notes to Consolidated Financial Statements.

1. BASIS OF PRESENTATION

These interim Consolidated Financial Statements do not conform in all respects to the disclosure requirements of Canadian generally accepted accounting principles for annual financial statements and should, therefore, be read in conjunction with the annual Consolidated Financial Statements of Hydro One Inc. (Hydro One or the Company) for the year ending December 31, 2009 which include information necessary or useful to understanding the Company's business and financial statement presentation. In particular, the Company's significant accounting policies and practices are presented as Note 2 to the annual Consolidated Financial Statements, and have been consistently applied in the preparation of these interim Consolidated Financial Statements.

The demand for electricity generally follows normal weather-related variations, and therefore the Company's energy-related revenues, all other things being equal, will tend to be higher in the first and third quarters than in the second and fourth quarters.

2. ACCOUNTING CHANGES

Change in Accounting Policy – Income Taxes

Effective January 1, 2009, the Company adopted amendments to the CICA Handbook Section 3465 - *Income Taxes* and CICA Handbook Section 1100 - *Generally Accepted Accounting Principles*. These amended sections establish new standards for the recognition, measurement, presentation and disclosure of future income tax assets and liabilities of rate-regulated enterprises.

For transactions and events that cause temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes, the adoption of these amended sections requires the recognition of future income tax assets and liabilities, and correspondingly the recognition of regulatory liabilities and assets. The temporary differences primarily relate to capital cost allowance in excess of deprecation and employee future benefits other than pension.

As a result of adopting these amended standards, on January 1, 2009, the Company recognized current future income tax assets of $20 million, long-term future income tax assets of $12 million and long-term future income tax liabilities of $503 million. The Company also recognized corresponding current regulatory liabilities of $29 million, long-term regulatory liabilities of $14 million and long-term regulatory assets of $526 million. An adjustment to retained earnings of $12 million was recorded as at January 1, 2009 for the cumulative earnings impact of future income tax assets and liabilities as at December 31, 2008 that are excluded from the rate-setting process.

3. DIVIDENDS

During the three months ended September 30, 2010, preferred dividends in the amount of $4 million (2009 - $4 million) and common dividends in the amount of $nil (2009 - $22 million) were declared. During the nine months ended September 30, 2010, preferred dividends in the amount of $13 million (2009 - $13 million) and common dividends in the amount of $10 million (2009 - $148 million) were declared.

4. LONG-TERM INVESTMENT

On January 22, 2010, Hydro One purchased $250 million in Province of Ontario Floating Rate Notes maturing on November 19, 2014 as a form of alternate liquidity to supplement its bank credit facilities. The Company has classified this investment as held-for-trading and therefore it has been recorded at fair value on the Consolidated Balance Sheet.

5. RATE-SETTING

Hydro One Networks Inc. (Hydro One Networks) Distribution Rate Decision

On April 9, 2010, the OEB released its decision regarding Hydro One Networks' rate application in respect of its Distribution Business. Subsequent to the decision, the OEB issued a final rate order which approved a revenue requirement of $1,146 million for 2010, reflecting a rate increase of approximately 9.3%. The proposed revenue requirement of $1,236 million for 2011 will be finalized following the September 2010 Consensus Forecast when the 2011 return on equity is forecasted. As part of the decision, the OEB also approved certain distribution-related deferral account balances sought by Hydro One in its application including retail settlement variance accounts, regulatory asset recovery account I, retail cost variance accounts and smart meters. The OEB ordered that the approved balances be aggregated into a single regulatory account (Rider 6) to be recovered over an 18-month period from May 1, 2010 to December 31, 2011. Further, the OEB requested the establishment of deferral accounts which track the difference between the revenue recorded on the basis of Green Energy Plan expenditures incurred and actual recoveries received under the approved rider. The OEB also approved a deferral account to record the revenue requirement impact of the harmonization of the provincial sales tax (PST) and federal goods and services tax effective July 1, 2010. Any estimated PST savings in approved rates will be brought forward for disposition in future rate applications.

As part of the decision, the OEB required Hydro One Networks to track the dollar value of variances between the OEB-approved line losses recovered in rates and actual line losses, commencing January 1, 2010. The OEB directed Hydro One Networks to bring this analysis forward to its next cost of service proceeding for the issue to be further examined.

The OEB further directed Hydro One Networks to investigate the effects of Conservation and Demand Management (CDM) programs on its load forecast, and required the Company to prepare analysis specific to its CDM actual volume reductions compared to forecast.

Currently, no amounts have been recorded for distribution lines losses and CDM. Management will continue to assess whether the results of the analysis in these areas requires the recognition of a regulatory liability.

Special Purpose Charge (SPC)

On April 9, 2010, the OEB issued a letter to all electricity distributors regarding the SPC Assessment under Section 26.1 of the *Ontario Energy Board Act, 1998*. The SPC has been established to enable the recovery of the expenses incurred and the expenditures made by the Ministry of Energy and Infrastructure (MEI) in respect of its energy conservation and renewable energy programs.

Along with the OEB's letter, the MEI set out the amount that Hydro One was assessed for the SPC, amounting to approximately $11 million. This amount was recorded in an OEB established variance account which captures any difference in the amount remitted for the SPC assessment and the cumulative amounts recovered from customers on account of the assessment. Recovery of the SPC assessment from customers commenced May 1, 2010, and is recovered on a volumetric basis.

6. LONG-TERM DEBT

During the nine months ended September 30, 2010, Hydro One issued additional notes under the Company's Medium-Term Note Program.

The first issue on January 22, 2010 was an additional offering of 3.13% notes with a principal amount of $500 million. The notes mature on November 19, 2014 and were originally issued on November 19, 2009 for $250 million, bringing the total amount outstanding for this issue to $750 million.

The second issue on March 15, 2010 was an offering of 4.40% notes with a principal amount of $300 million. The notes mature on June 1, 2020.

The third issue on March 15, 2010 was an additional offering of 5.49% notes with a principal amount of $200 million. The notes mature on July 16, 2040 and were originally issued on July 16, 2009 for $300 million, bringing the total amount outstanding for this issue to $500 million.

The fourth issue on September 13, 2010 was an offering of 2.95% notes with a principal amount of $250 million. The notes mature on September 11, 2015. On the same day, the Company made an additional offering of 5.00% notes with a principal amount of $250 million. The notes mature on October 19, 2046 and were originally issued on October 19, 2006 for $75 million, bringing the total amount outstanding for this issue to $325 million.

On January 22, 2010, Hydro One entered into two $250 million notional principal amount fixed-to-floating interest rate swaps to convert $500 million of Hydro One's 3.13% coupon note maturing November 19, 2014, into three-month variable rate debt. The Company designated these swaps as fair value hedges associated with interest rate risk with the changes in fair value recognized in the Consolidated Statement of Operations for the period, along with changes in the fair value of the fixed rate note that is attributable to the hedged risk. To the extent the hedge is ineffective, the ineffective amount is recognized immediately to financing charges in the Consolidated Statement of Operations, and this amount was insignificant for the period.

In the second quarter, the Company entered into four forward rate agreements in order to lock-in four interest rate resets on the floating rate it pays on $500 million of floating rate debt, with settlement dates of May 19, 2010, June 3, 2010, August 19, 2010 and September 3, 2010 respectively. The four forward rate agreements were classified as held-for-trading and measured at fair value. The cash settlements on the four forward rate agreements were not significant and were made by the Company on May 19, June 3, August 19 and September 3, 2010.

7. EMPLOYEE FUTURE BENEFITS

Total benefit costs are as follows:

	Three months ended September 30		Nine months ended September 30	
(Canadian dollars in millions)	**2010**	**2009**	**2010**	**2009**
Pension				
Net periodic benefit cost	46	32	137	97
Pension fund contribution	30	28	89	84
Less: Portion attributable to labour and capitalized as part of the cost of fixed assets	12	11	36	33
Charged to results of operations	18	17	53	51
Employee Future Benefits Other than Pension				
Net periodic benefit cost	23	22	68	62
Less: Portion attributable to labour and capitalized as part of the cost of fixed assets	9	9	27	25
Charged to results of operations	14	13	41	37

8. CONSOLIDATED STATEMENTS OF CASH FLOWS

For the purposes of the Consolidated Statements of Cash Flows, "cash and cash equivalents" refers to the Consolidated Balance Sheet items "short-term investments" and "bank indebtedness."

9. SEGMENTED REPORTING

Hydro One has three reportable segments:

- The Transmission Business, which comprises the core business of providing transportation and connection services, is responsible for transmitting electricity throughout the Ontario electricity grid;

- The Distribution Business, which comprises the core business of delivering and selling electricity to customers; and
- An "other" segment primarily consisting of a telecommunications business.

The designation of segments is based on a combination of regulatory status and the nature of the products and services provided. Segment information on the above basis is as follows:

Three months ended September 30 (Canadian dollars in millions)	Transmission	Distribution	Other	Consolidated
2010				
Segment profit				
Revenues	376	970	14	1,360
Purchased power	-	638	-	638
Operation, maintenance and administration	90	147	16	253
Depreciation and amortization	72	76	2	150
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	214	109	(4)	319
Financing charges				82
Income before provision for payments in lieu of corporate income taxes				237
Capital expenditures	234	165	2	401
2009				
Segment profit				
Revenues	296	831	17	1,144
Purchased power	-	547	-	547
Operation, maintenance and administration	109	144	14	267
Depreciation and amortization	62	75	2	139
Income before financing charges and provision for payments in lieu of corporate income taxes	125	65	1	191
Financing charges				79
Income before provision for payments in lieu of corporate income taxes				112
Capital expenditures	233	166	1	400

Nine months ended September 30 (Canadian dollars in millions)	Transmission	Distribution	Other	Consolidated
2010				
Segment profit				
Revenues	1,002	2,795	47	3,844
Purchased power	-	1,835	-	1,835
Operation, maintenance and administration	300	432	45	777
Depreciation and amortization	202	224	7	433
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	500	304	(5)	799
Financing charges				255
Income before provision for payments in lieu of corporate income taxes				544
Capital expenditures	638	465	3	1,106

Nine months ended September 30 (Canadian dollars in millions)	Transmission	Distribution	Other	Consolidated
2009				
Segment profit				
Revenues	869	2,620	48	3,537
Purchased power	-	1,731	-	1,731
Operation, maintenance and administration	332	418	41	791
Depreciation and amortization	177	208	7	392
Income before financing charges and provision for payments in lieu of corporate income taxes	360	263	-	623
Financing charges				225
Income before provision for payments in lieu of corporate income taxes				398
Capital expenditures	638	477	4	1,119

(Canadian dollars in millions)	September 30, 2010	December 31, 2009
Total assets		
Transmission	9,527	8,993
Distribution	6,745	6,481
Other	1,082	161
	17,354	15,635

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

10. CLAIM BY WHITESAND AND RED ROCK FIRST NATION BANDS

On July 27, 2010, the court order formally dismissing the litigation against Hydro One by the Whitesand First Nation Band and the Red Rock First Nation Band was issued.

11. COMPARATIVE FIGURES

The comparative unaudited interim Consolidated Financial Statements have been reclassified from statements previously presented to conform to the presentation of the September 30, 2010 unaudited interim Consolidated Financial Statements.

In the third quarter, the Company has changed the presentation of tax balances associated with certain temporary differences related to intangible assets and other regulatory account balances, to reflect how these balances will ultimately be settled. As a result, the Company has reclassified the tax balances associated with these temporary differences, such that the amount of future income tax liabilities and the related net regulatory asset in the interim period balance sheet, and in the comparative December 31, 2009 balance sheet, have been reduced by $160 million. The change in presentation has no impact on revenue or operating cash flow.